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«Contracts-for-Difference and Nuclear Flexibility: A Path to Complementing Renewables»

by

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Abstract

Contracts-for-Difference (CfDs) shift the electricity price risk from producers to third parties, typically governments, and have been instrumental in fostering renewable energy investment in liberalized electricity markets. As Western countries turn to CfDs to support new nuclear power plant (NPP) investments, concerns arise regarding their impact on short-term dispatch. By shielding producers from real-time wholesale prices, CfDs can distort dispatch incentives, leading to inefficiencies. Innovative CfD designs have been proposed in the literature to mitigate these effects, some of which have already materialized in some countries. This paper assesses how different CfD designs influence nuclear dispatch decisions in a projected 2040 Central Western Europe electricity market. Using a partial equilibrium model formulated as a Mathematical Program with Equilibrium Constraints (MPEC) and solved as a Mixed Integer Quadratically Constrained Program (MIQCP), we reveal unintended consequences. Notably, a CfD with negative-price interruption can induce NPP operators to reduce availability in moments of soaring prices, resulting in higher general prices than the first-best solution. This results from nuclear plants' limited flexibility: operators must balance producing at low output levels during negative prices with maximizing production at other times to secure the strike price. We show how a non-production-based CfD design can partially alleviate this problem and improve NPPs' short-term dispatch, although we show the latter cannot restore the optimal dispatch either. These findings emphasize the critical importance of careful CfD design and ongoing regulatory oversight as governments expand CfD applications to nuclear power.

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Keywords: Nuclear Energy, Contract-for-Difference, Flexibility

1. Introduction

Modern electricity grids are undergoing a profound transformation to reduce greenhouse gas emissions, driven by the large-scale integration of Variable Renewable Energy sources (VREs), such as solar photovoltaics and wind turbines. However, the increasing reliance on these weather-dependent energy sources, in systems where maintaining a continuous balance between supply and demand is critical to avoid blackouts, presents a significant challenge: ensuring adequate flexibility within the power system.

Flexibility, defined as the ability to adapt to fluctuations in supply and demand, is multidimensional, and there is a growing need for bringing flexibility in electricity systems due to the rapid rollout of VREs (Ulbig & Andersson, 2015). Existing market structures have been proven to fail to send the right incentives for flexibility due to the presence of externalities, leading to inefficient valuation of flexible resources (Mays, 2021). However, solutions exist to enhance system flexibility and cope with the variable nature of VREs. They include energy storage technologies, Demand Side Management (DSM), expanded interconnections, and an increased use of thermal power plants in a load-following mode, where output varies dynamically to adjust to the residual load. Nuclear Power Plants (NPPs) are a candidate for this latter source of flexibility, being a low-carbon and dispatchable electricity source. Indeed, even though NPPs have historically been viewed as inflexible, this is mainly because of the financial structure of nuclear projects, which display large fixed costs and regulatory constraints rather than technical limitations. France, where nuclear power constitutes a significant share of the electricity mix, has historically operated reactors with the ability to somehow modulate output to follow demand patterns. The current technological options for investment in nuclear in Western countries — the American Westinghouse "AP-1000" and the European EDF "EPR" — both allow for flexible operations.

Although nuclear energy has long been a source of low-carbon electricity, its importance has been somewhat overshadowed until recent years. After a period of rapid growth from the 1960s to the 1980s, the subsequent decades saw a significant decrease in the number of new nuclear projects being constructed. This decrease was mainly due to cost overruns from previous endeavors and the significant impact of accidents such as Three Mile Island (TMI) in 1979, Chernobyl in 1986, and Fukushima in 2011. Rapidly rising fuel prices and the global recession following the second oil shock resulted in stagnant or negative electricity demand growth and severe cash shortages for utilities. Utilities with extensive plant construction plans were hit particularly hard, especially for NPPs. Financial markets downgraded the bond ratings of these utilities, increasing borrowing costs. Faced with cash shortages, rising construction costs, and limited demand for new plants, utilities had to scale back their construction programs significantly (Thomas, 1988). Consequently, most NPPs additions occurred before 1990 in the Western world.

However, nuclear power may be on the verge of a "renaissance" after the Russian invasion of Ukraine, and concerns about climate change mitigation have highlighted its capability to provide low-carbon dispatchable energy with minimal dependence on foreign trade. Furthermore, developed nations are increasingly demonstrating a keen interest in leading the charge toward nuclear energy, partly aligned with ambitions to re-industrialize their economies. In Europe, a coalition of countries has gathered into the so-called "Nuclear Alliance" to promote the development of nuclear energy on the continent. They officially aim to develop 150GW of nuclear power by 2050, keeping the nuclear share at the current 25% of the electricity mix[1]. In the US, nuclear also experiences a renewed interest. Federal legislation, such as the Bipartisan Infrastructure Law of 2021, the Inflation Reduction Act of 2022, and the Nuclear Fuel Security Act within the 2023 National Defense Authorization Act aim at establishing a stable long-term business environment for nuclear energy in the country[2]. A report from the Department of Energy suggests that the country could rely on 300GW of nuclear capacity by 2050, which would be a three-fold increase from the current installed capacity (DoE, 2023).

Financing new NPPs, however, remains challenging due to their capital intensity and long project timelines. Current support mechanisms often draw on Contracts for Difference (CfDs), a tool widely used for VRE projects, as seen in the Hinkley Point C project in the UK and the Dukovany 5 plant in the Czech Republic. CfDs have become a standard instrument for derisking energy investments, with more than 50% of global offshore wind financing conducted under such schemes (Beiter et al., 2023). CfDs provide revenue stability by guaranteeing a steady price over the contract duration. Under a two-sided CfD, the government compensates the generator when market prices fall below the contracted strike price and receives clawback payments when market prices exceed it. Importantly, CfDs do not inherently constitute subsidies and should rather be considered as derisking tools, as net payments can favor the government if market prices remain high for prolonged periods (Beiter et al., 2023). While CfDs reduce financial risks and facilitate investment, they may

[1]www.ecologie.gouv.fr
[2]www.nei.org

undermine flexibility by decoupling revenues from real-time operational needs. For dispatchable technologies such as NPPs, this lack of alignment potentially has important impacts, as operators may be incentivized to maximize production rather than market value. Such inefficiencies can increase the overall cost of transitioning to a low-carbon energy system. Furthermore, while CfDs' effectiveness in mitigating market power is aknowledged since the beginning of power markets liberalization (D. M. Newbery, 1995), their interaction with nuclear-specific flexibility constraints remains unexplored.

This paper examines the implications of different CfD designs on both the operational incentives and market power potential of nuclear power plants. Through a combination of analytical modeling and numerical simulations, we analyze how various CfD schemes affect nuclear operators' strategic behavior, dispatch decisions, and flexibility provision. Using the Central Western European (CWE) electricity market as a case study, we quantify the impacts of these schemes on price levels, firm profitability, and system efficiency. This study contributes to the evolving literature on CfDs for low-carbon technologies in the power market, which increasingly considers the compatibility of these instruments with system needs. We offer new insights into how CfD design influence operational behavior and system outcomes by extending the discussion to nuclear energy.

From a methodological perspective, we develop a numerical bilevel optimization program written as a Mathematical Problem with Equilibrium Constraints (MPEC) and recast as a Mixed Integer Quadratic Constrained Program (MIQCP). This allows for an in-depth analysis of the dispatch decision of a nuclear monopolist in the CWE region, in 2040.

The paper is structured as follows. Section 2 presents the technical characteristics of NPPs and how they can provide a valuable complement to VREs. Section 3 reviews the rationale behind CfDs and their role in electricity market evolution. Section 4 investigates how different kinds of CfD designs impact the short-term dispatch decisions of an NPP, using a simple analytical framework. Section 5 presents a numerical case study analyzing the effects of CfDs on nuclear dispatch. Section 6 presents the results, and Section 7 offers some concluding remarks.

2. Nuclear power plants: facing economic challenges and technical constraints

2.1. Historical Financing and the Emergence of CfDs for Nuclear Projects

The early development of nuclear energy historically relied on strong public support, in the midst of the Cold War and the race for nuclear supremacy. In the

United States, for instance, federal subsidies from 1943 to 1999 reached $145 billion (1999 dollars), representing over 96% of the total subsidies for electricity generation technologies. Nevertheless, since a substantial amount of NPPs were built in the '70s-80s with few federal supports, the fission-related nuclear power subsidies eventually resulted in a cost of 1.2¢/kWh (Goldberg, 2000). Costs were often passed on to consumers through rate-of-return regulation, which significantly lowered investment risk. In parallel, the Price-Anderson Act (1959) limited liability in the event of an accident, shielding investors from catastrophic financial exposure.

In Europe, large-scale nuclear deployment was largely driven by state-owned utilities. The French case exemplifies this model: EDF financed an ambitious nuclear programme, initially through direct state agreements and later via capital markets, benefiting from its AAA credit rating and regulated tariffs. High electricity demand in the 1970s further supported these investments. Yet, as liberalization gained traction across Europe, such publicly driven financing models became less viable. Utilities increasingly faced market exposure, while governments withdrew from direct involvement in project funding.

Today, the liberalized context poses significant challenges for new nuclear investment. The capital-intensive nature of NPPs, long construction timelines, and uncertain electricity prices deter private investors, especially when compared to renewables, which have experienced a sharp decline in cost in the past decade. While traditional models such as full public ownership or corporate financing still persist in some countries – notably China or Hungary – they are increasingly rare in liberalised Western markets, where fiscal constraints and regulatory neutrality are dominant principles (IAEA, 2018).

CfDs have emerged as a promising solution to de-risk nuclear investments in this context. They offer a hedge against volatile market conditions without requiring upfront public capital by guaranteeing a long-term strike price for electricity output. The UK's Hinkley Point C project marked a turning point, applying a CfD model to nuclear, mirroring practices often used in VRE projects to secure cashflows and lower the cost of capital. In France, the National "Cour des Comptes" (Court of Auditors) has mandated a revenue guarantee for EDF's new reactor investments and the need for a better sharing of risks (des Comptes, 2019). This would likely take the form of a CfD, given the recent decision of the European Commission to make this form of long-term contract the standard for derisking investments in the power sector (Regulation (EU) 2024/1747).

2.2. What does partial dispatchability mean?

Some NPP designs allow for varying the output to adapt to fluctuating needs on the grid, challenging the conventional view of nuclear as an inflexible technology. In the US, the existing fleet of NPPs can reduce output by 20% per hour but require six to eight hours to return to full load, limiting their ability to rapidly respond to intermittent generation patterns such as daily load cycles (MIT, 2011). However, specific designs can enable significant load-following capabilities. French NPPs, which provided 67% of the country's electricity production in 2024, have operated flexibly for decades through modifications to the original Westinghouse Pressurized Water Reactor (PWR) design (Thomas, 1988). Modern 3rd generation reactors, including the EDF "EPR" and Westinghouse "AP1000", demonstrate even greater flexibility, with ramping capabilities of 3-5% of full load per minute. This allows these units to transition from minimum operating capacity (20%) to full load within 30 minutes (Lynch et al., 2022).

Although recent NPPs are technically capable of rapid load changes, operational constraints limit their flexibility in practice. Frequent cycling induces mechanical stress on critical components—including boilers, turbines, and auxiliary systems—leading to accelerated degradation, increased maintenance requirements, and higher operational costs, particularly during start-up and shutdown events (Wang & Shahidehpour, 1994). Additionally, nuclear-specific constraints like the Xenon effect — the accumulation of xenon-135, a fission product with a high neutron absorption capacity, lowering reactivity after power reductions — further restrict flexibility. International standards reflect these limitations, setting maximum thresholds of 2 load-following operations daily, 5 per week, and 200 per year (European Utility Requirements, 2012). In practice, operators utilize significantly less flexibility than these limits permit. For example, French NPPs averaged only 25 cycles in 2024 (own calculation from ENTSO-e transparency data), despite increasing opportunities for flexible operation as evidenced by negative prices occurring for over 300 hours, twice the frequency observed in 2023. This shows NPP operators sometimes prefer to produce at a loss rather than lowering production, indicating the actual nuclear flexibility can be far lower than the theoretical bounds we find in the grey literature.

Some papers have delved into the modeling of nuclear partial flexibility. Cany et al. (2018) analyzes the historical practice of nuclear cycling in the French case and finds that French NPPs have been able to provide flexibility to the grid, with further room for improvement, but also potential adverse effects on the number of unplanned outages. Loisel et al. (2018) shows NPPs' load factors would decrease to less than 60% in Europe in 2050 if the full extent of nuclear flexibility is used, challenging its economic viability as the technology is capital intensive and has historically relied on high load factors to recoup its significant fixed costs. In a recent paper, one of us showed how the cycling constraint at the reactor scale can be approximated at the fleet scale by a linearization which allows us to model nuclear flexibility as a scarce stock that has to be used wisely across the year (Blanchard & Massol, 2025). All these papers show that a proper way of modeling nuclear flexibility is thus through a constraint on cycling rather than on ramping, which is therefore the modeling we use in this paper.

3. CfDs: a key instrument for the energy transition with inherent limitations

3.1. The incompleteness of power markets

Theoretically, electricity markets should provide optimal investment signals for production capacity. In an ideal energy-only market, deviations from equilibrium trigger price changes that incentivize or slow investments based on demand. For instance, a supply shock, such as rising gas costs, increases average prices and volatility, spurring investments in alternative technologies that can capitalize on high-value periods. However, as Hogan (2005) argues, this framework is flawed due to fundamental market failures.

Electricity's unique characteristics, including non-storability and demand inelasticity, make it a very peculiar good. Unlike storable commodities like oil or wheat, electricity markets face pronounced hourly price fluctuations and can be very geographically fragmented, which hinders effective hedging and misaligns forward prices with market fundamentals (Defeuilley & Meunier, 2006; Geman, 2005). As a consequence, forward markets, typically limited to 3–5 years, fail to offer sufficient hedging opportunities for new investments. This shortfall undermines the viability of merchant plant models — Even combined-cycle gas turbines (CCGTs), which benefit from natural hedging as price setters, have faced financial difficulties in the past as evidenced by the bankruptcies of merchant plants in the liberalized U.S. and UK markets during the early 2000s. In a recent work, Dimanchev et al. (2024) has shown how this lack of long-term markets hinders the spread of clean technologies and rather promotes fossil fuel plants.

To address these issues, capacity markets and CfDs have been introduced in Europe, fostering supply adequacy by derisking long-term investments. CfDs allow the explicit swap of the revenue streams from the asset with one that is more stable (Beiter et al., 2023). Under this mechanism, a producer receives a payment from the government to cover the difference between a predefined strike price and a reference price, typically the day-ahead wholesale market price. Conversely, if the reference price exceeds the strike price, the producer returns the surplus to the government through a clawback payment. This structure shields the producer entirely from price fluctuations, ensuring revenue stability that depends solely on their cumulative production. The mechanism echoes earlier utility practices, where costs were passed on to consumers via electricity tax rates. Thus, CfDs take the vacant place of long-term contracting, allowing project developers to lower the project risk.

In the United States, the adoption of CfDs as practised in many European jurisdictions is constrained by federal regulatory boundaries. Specifically, CfDs that establish a fixed strike price for electricity generation have been judged to infringe upon the exclusive authority of the Federal Energy Regulatory Commission (FERC), which regulates wholesale electricity prices. FERC prohibits state-level procurement mechanisms that directly interfere with a generator's FERC-approved wholesale rate – that is, states may not implement measures that effectively override or replace market-based prices. As a result, conventional two-sided CfDs – where the state pays or receives the difference between the strike price and the wholesale market price – are not permissible under current regulatory interpretations. Nevertheless, several U.S. states have developed functionally similar instruments, such as long-term regulated Power Purchase Agreements (PPAs) or Renewable Energy Certificate (REC) schemes, particularly in the context of offshore wind development. These contracts also ensure price stability, but they do so by remunerating producers a fixed amount per megawatt-hour delivered, without explicitly referencing or offsetting wholesale market prices — thus remaining within the bounds of state authority.

3.2. Market Power Concerns

The proliferation of CfDs and the political push for long-term contracting (forwards, PPAs) also reflects a regulatory objective to mitigate market power in electricity markets. As noted by Allaz and Vila (1993) and Wolak (2000), forward contracts can dampen the effects of market power and promote competitive behavior among market participants.

The adoption of these measures followed the liberalization of electricity markets, a process marred by significant episodes of market manipulation. The Californian electricity crisis of 2001, driven by prices far exceeding competitive levels, highlighted systemic inefficiencies that had been evident since 1998 (Kumar David & Fushuan Wen, 2001). Similarly, price spikes in the UK electricity market during 1993 were attributed to strategic manipulation by dominant players. These cases underline the challenges of measuring market power in electricity markets, where technical specificities, such as low demand elasticity and grid congestion, can create temporary monopolies. Conventional metrics like the Herfindahl-Hirschman Index (HHI), Lerner Index, and Price-Cost Margin often fail to capture these transient dynamics (Lundin, 2021).

In response, regulators have increasingly relied on bilateral contracts, including CfDs, to encourage competitive bidding. Empirical studies confirm the pro-competitive effects of forward contracting (Serra, 2013). However, poorly designed subsidies can counteract these benefits by incentivizing capacity withdrawals or inefficient operational practices, as highlighted by Chaiken et al. (2021).

NPPs are not excluded from these discussions about market power abuse. The fact that NPPs can provide flexibility to the system by varying output is an asset. Still, it can also trigger concerns regarding the potential use of this flexibility for strategic purposes. Past abuses by nuclear operators further illustrate these risks. In the Scandinavian market, for example, a former head of production planning at Vattenfall admitted in a 2006 interview that the company deliberately reduced nuclear output during periods of high prices to inflate market prices.[3]

The complexity of nuclear plant operations, including fuel optimization and strategic maintenance, makes it difficult to detect price manipulation. Opportunity costs indeed play a central role in determining bidding strategies for nuclear operators, providing avenues for strategic output reductions to influence prices (Moiseeva et al., 2017; Rintamäki et al., 2020). Operators may lack incentives to optimize plant availability if they acknowledge their market power, as past practices in the England and Wales market in the 1990s have shown. Large suppliers at the time intentionally reported lower availability rates compared to independent power producers (Kumar David & Fushuan Wen, 2001). Crampes and Renault (2023) have also shown that partially flexible generators like NPPs may not be willing to increase their flexibility potential, as keeping some rigidity in their dispatch planning gives them an edge compared to a perfectly flexible technology on forward markets. Indeed, when contracting on the day ahead, the relatively inflexible nature of a technology confers credibility on the production schedule and results in a Stackelberg-like oligopolistic market structure.

3.3. Classical CfDs and Their Limitations

Properly designed CfDs can thus address two key challenges in modern power markets: providing long-term revenue stability for clean technologies to encourage investment and reducing incentives for anti-competitive behavior. However, they have notable limitations, particularly in short-term dispatch. Traditional CfDs remunerate producers based on output, encouraging them to maximize production

[3]The transcription can be found at sverigesradio.se

rather than optimizing market value, which often results in a so-called "produce-and-forget" behavior. As renewable energy penetration grows, this limitation becomes increasingly critical, worsening issues like grid congestion and the prevalence of negative price events. Thus, CfDs can fail to address the flexibility challenges arising from the spread of VREs. For partially flexible technologies such as nuclear power, which can offer valuable operational flexibility to the system, classical CfDs disincentivize flexible behavior, resulting in suboptimal flexibility provision and inefficient utilization of these assets.

A growing body of literature has recently explored how CfDs can be refined to better align the operational behavior of generators with system needs. This is particularly important for dispatchable technologies like nuclear power, whose role in flexible system balancing is expected to increase. Several alternative CfD designs have emerged, offering various mechanisms to improve incentive alignment beyond the traditional volume-based approach.

Among these, "yardstick", "financial", or "Capability" CfDs — the terminology we adopt in the remainder of this paper — decouple subsidy payments from actual production levels (ENTSO-E, 2024; Eurelectric, 2024; D. Newbery, 2023; Schlecht et al., 2024). Instead of remunerating generators based on their real-time output, these schemes rely on a reference generation profile to determine both the subsidy and clawback payments. The government pays a fixed amount every hour, independent of the actual production, while the generator must reimburse what a benchmark profile — representing a typical or forecasted output pattern — would have earned on the wholesale market. This design incentivizes generators to outperform the reference profile, akin to how yardstick competition incentivizes firms by comparing their performance against a benchmark to determine regulated payouts, as first proposed by Baiman and Demski (1980) and further elaborated by Tirole and Laffont (1993).

This design aims to restore incentives for market-value maximisation. Asset owners are encouraged to outperform the reference profile by adjusting their dispatch to price signals. In the case of variable renewables, the reference may be a location-averaged forecast or historical norm. For dispatchable technologies such as nuclear, it could take the form of a flat "generation ribbon". When applied in this context, the Capability CfD resembles a long-term forward contract, albeit one that can extend across the full economic life of the plant. This framework incentivises operators to perform cycling operations during low-price periods, reduce planned outages during high-demand seasons (such as winters in Europe or summers in the US), and improve overall plant availability. Producers still face what is known as basis risk — the risk of deviating from a predefined production profile — which can result in financial losses. This is comparable to a situation where a producer sells electricity on forward markets but is unable to meet its contractual obligations in real-time. In such cases, the producer must purchase energy on the spot market to resell it to the counterparty in order to fulfill the contract. To enable broader investor participation, the CfD can also be structured to cover only part of the plant's capacity, with the remaining volume contracted via standard forward contracts or PPAs (ENTSO-E, 2024).

Despite their conceptual appeal, these innovative designs have yet to be implemented in practice. Their complexity and lack of transparency have hindered political and regulatory uptake, as stakeholders tend to favour simpler instruments that are easier to communicate and administer. However, this inertia is gradually being challenged. In light of the increasing prevalence of negative wholesale prices across Europe since 2020, the European Union now mandates that state aid instruments — including CfDs — better reflect short-term system needs.[4]

This policy shift has already influenced practice. CfDs incorporating negative-price interruption have become the new standard, most notably in the Dukovany 5 nuclear project in the Czech Republic. These contracts suspend support payments during periods when the reference market price — usually the day-ahead price — turns negative. As a result, producers are incentivised to limit their exposure to such price events. This may involve adjusting design choices (e.g. orienting solar panels east–west to flatten output), improving locational diversity, or curtailing output when surplus generation depresses prices. By doing so, these designs help reduce the occurrence and depth of negative prices, thus enhancing market efficiency while preserving long-term investment security.

4. Analytical insights for nuclear dispatch under different CfD designs

This section intends to draw analytical intuitions regarding the impacts of different CfD designs on nuclear dispatch. Our model aims to be instructive rather than exhaustive, and this is why we consider a stylized two-period case with carefully chosen assumptions. We also consider the CfD design under scope to apply for the full production capacity of the nuclear asset. The numerical model of section 5 expands our results in a more realistic case.

4.1. Optimal dispatch

Consider a market situation as depicted in Figure 1, composed of one period with very high electricity production from renewables (q_1^{VRE}) followed by a moment

[4] Guidelines on State Aid for Climate, Environmental Protection, and Energy, 2022

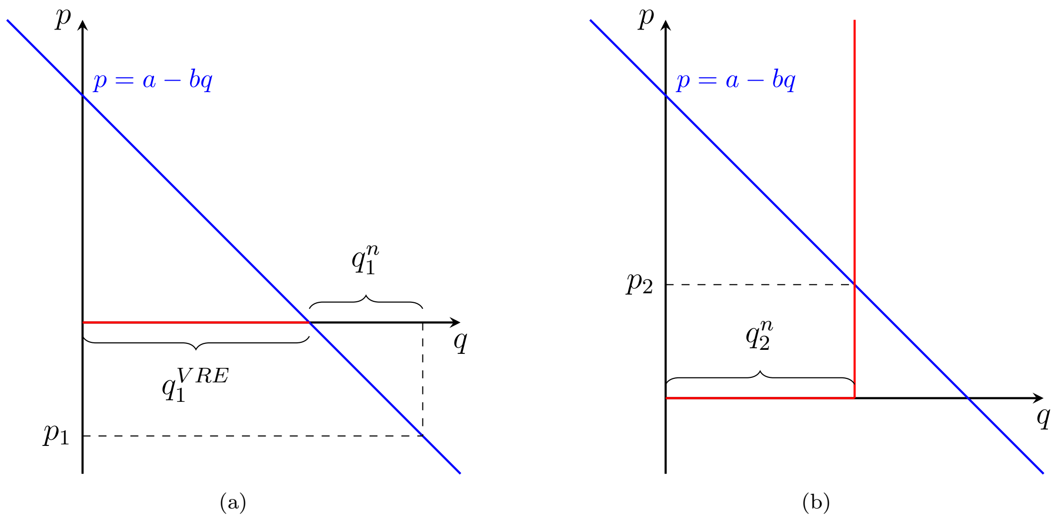


Figure 1: Market clearing for two periods

of low renewable production, which drives prices up. The electricity demand is characterized by an inverse demand function $p_t = a - bd_t$, with d_t the demand at time t and p_t the market price resulting from the clearing process. The optimum nuclear dispatch is defined by the following program, where the nuclear operator is a price taker and maximizes profit defined as

$$\Pi_{\mathrm{PC}} = (p_1 - c)q_1 + (p_2 - c)q_2. \tag{1}$$

We assume the inverse demand function is the same in both timeframes, and the production from renewable in time 1 exactly equals the demand, i.e., net demand is null and $q_1^{VRE} = \frac{a}{b}$. Since nuclear flexibility is limited, nuclear production at time 1 (q_1) can be positive, resulting in a negative price $p_1 = -bq_1 \leq 0$ (we assume the production from VRE is not cutailed, as it can be the case due to remaining feed-in-tariffs, grid congestion constraints, or guarantee of origin). In time 2, VRE production is zero, and nuclear production reaches q_2. Since we consider nuclear flexibility to be binding, nuclear production levels in periods $1, 2$ are constrained by the maximum allowed output deviation L, and $q_2 \leq q_1 + L$. For the sake of simplicity, we consider the price to be set by the demand (scarcity pricing, yielding $p_2 = a - bq_2$).

The profit-maximization problem reads

$$\begin{aligned}\max_{q_1,q_2} \quad & (p_1-c)q_1+(p_2-c)q_2\\ s.t. \quad & q_2-q_1 \le L \quad (\nu)\\ & q_{1,2}\le Q \quad (\mu_1,\mu_2)\\ & q_{1,2}\ge 0 \quad (\rho_1,\rho_2),\end{aligned}$$

with Q the nameplate capacity of nuclear, c the marginal cost of nuclear, and variables in parentheses are Lagrange multipliers associated with the corresponding constraints. The Lagrangian and Karush-Kuhn-Tucker conditions write

$$\mathcal{L} =(p_1-c)q_1+(p_2-c)q_2-\nu(q_2-q_1-L)-\mu_1(q_1-Q)-\mu_2(q_2-Q),$$

$$0 \le -p_1+c-\nu+\mu_1 \perp q_1 \ge 0 \tag{2}$$
$$0 \le -p_2+c+\nu+\mu_2 \perp q_2 \ge 0 \tag{3}$$
$$0 \le -q_2+q_1+L \perp \nu \ge 0 \tag{4}$$
$$0 \le -q_1+Q \perp \mu_1 \ge 0 \tag{5}$$
$$0 \le -q_2+Q \perp \mu_2 \ge 0. \tag{6}$$
$$\tag{7}$$

The derivative of the objective function according to q_1 is $\frac{\partial \Pi}{\partial q_1}=p_1-c<0)$ which means we have $\mu_1=0$. On the other hand, profit and the generation decision at time 2 are positively correlated ($\frac{\partial \Pi}{\partial q_2}=p_2-c>0$) and the flexibility constraint is saturated, leading to $q_2=q_1+L$, and $\nu>0$. In order to compare the dispatch decisions across the different CfD designs, we frame the question as "what condition on the parameters of the problem yields a maximum generation in time 2, i.e. $q_2=Q$". We thus pose $q_2=Q$, which yields $q_1=Q-L$ and from (2)-(3), we find

$$\mu_2=a-2bQ+bL-2c\ge 0,$$

which ultimately gives the following condition on a

$$a \ge 2bQ-bL+2c=a^*_{PC}. \tag{8}$$

If we suppose $a\ge 2bQ-bL+2c$, $q_2<Q$ implies $\mu_2=0$, meaning $p_2=c+\nu$. Injecting in (2) yields $-p_1-p_2+2c\ge 0$, which is equivalent to $a\le 2bQ-bL+2c$, and we reach a contradiction (with the exception of the particular case of equality).

Thus, we showed $a \geq 2bQ - bL + 2c$ implies $q_2 = Q$. Price in time 2 can then be explicitly expressed

$$p_2^{PC} = b(Q - L) + 2c. \tag{9}$$

This expression reflects the opportunity cost of ramping up nuclear production in a system with limited flexibility. In order to reach full capacity in period 2 ($q_2 = Q$), the plant must already be producing $q_1 = Q - L$ in period 1, even if the price is negative. The resulting loss in period 1 must be compensated by a higher price in period 2. Hence, the price $p_2^{PC} = c + (c - p_1) = b(Q - L) + 2c$ incorporates not only the marginal cost of nuclear at time 2 (c), but also the loss incurred by producing in an earlier low-price period.

4.2. Strategic case

Consider a case where the nuclear operator acknowledges their market power, meaning the impact of dispatch on price is incorporated into the program, and the derivative $\frac{\partial p_t}{\partial q_1}$ now differs from zero. The objective function now reads

$$\Pi_{\mathrm{S}} = (-bq_1 - c)q_1 + (a - bq_2 - c)q_2, \tag{10}$$

and the KKT conditions are

$$\mathcal{L} =(-bq_1 - c)q_1 + (a - bq_2 - c)q_2 - \nu(q_2 - q_1 - L) - \mu_1(q_1 - Q) - \mu_2(q_2 - Q),$$

$$\begin{aligned}
&0 \leq 2bq_1 + c - \nu + \mu_1 \perp q_1 \geq 0\\
&0 \leq -a + 2bq_2 + c + \nu + \mu_2 \perp q_2 \geq 0\\
&0 \leq -q_2 + q_1 + L \perp \nu \geq 0\\
&0 \leq -q_1 + Q \perp \mu_1 \geq 0\\
&0 \leq -q_2 + Q \perp \mu_2 \geq 0.
\end{aligned}$$

Following the same assumptions we used in the PC case, we find the strategic nuclear operator to produce at nameplate capacity in time 2 if and only if

$$a \geq 4bQ - 2bL + 2c = a_S^*.$$

We compare this condition with the similar result of the PC case, and we find

$$a_S^* - a_{PC}^* = b(2Q - L) > 0,$$

which means a higher demand is needed for the strategic nuclear to produce at nameplate capacity compared to the competitive case. This means that, in the general case, the strategic nuclear operator produces less than (or equal to) the first-best optimal dispatch. We find the classical result of a strategic producer withholding capacity to artificially inflate prices and their profits at the expense of consumers' surplus.

4.3. Classical CfD

We define the classical CfD as a remuneration mechanism in which the generator's revenue is effectively decoupled from market prices and replaced by a fixed strike price, applied to actual output. The nuclear operator's profit-maximising problem under this scheme is given by:

$$\Pi_{\text{CfD}} = \sum_t (s - c) q_t, \tag{11}$$

with s the strike price. Under this arrangement, the operator has a clear incentive to maximise output irrespective of market conditions, as revenue is directly proportional to generation volume. This undermines the potential for flexible operation of the NPP, leading to systematic overproduction. As a result, market prices are depressed relative to the first-best dispatch outcome, adversely affecting the profitability of other generators and distorting the market equilibrium. Although this paper does not explore the long-term investment implications, it is worth noting that such distortions could also affect investment signals.

Importantly, lower market prices under the classical CfD do not necessarily imply an increase in consumer surplus. In fact, the subsidy burden associated with the CfD can be considerable — particularly in periods of negative prices, during which the operator receives the full strike price despite the reference price being negative. In these instances, the incentive to continue producing exacerbates price suppression. Assuming a significant overlap between consumers and taxpayers, the cost of these subsidies ultimately falls on the same group, potentially offsetting the gains from lower wholesale prices and diminishing net welfare.

4.4. CfD with negative-price interruption

This CfD design guarantees a strike price to generators but excludes payments when market prices are negative. Such a clause supposedly better aligns generator incentives with market conditions, incentivizing lowering output during hours of negative price while still providing revenue stability over the contract's lifetime. The profit function of the nuclear operator is

$$\Pi_{Neg} = \sum_t (p_t - c)q_t + \mathbb{1}_{p_t \geq 0} \sum_t (s - p_t)q_t, \tag{12}$$

with p_t the market price at time t, and $\mathbb{1}_{p_t \geq 0}$ an indicator variable that equals 1 if the price is non-negative, and 0 otherwise. In our two-period analytical model, the objective function of a nuclear operator under such a CfD contract is

$$\Pi_{\text{Neg}} = (p_1 - c)q_1 + (s - c)q_2.$$

Since the price is negative in time 1, the payment ceases for that period and resumes in time 2, when the price is positive.

Proposition 1. *Under the given assumptions and considering our two-stage model, a nuclear operator under a CfD with negative-price interruption produces at nameplate capacity in time 2 only if*

$$s \geq 2bQ - 2bL + 2c > p_2^{PC},$$

and nuclear underproduces compared to the optimum dispatch.

The formal proof is provided in Appendix A. The core intuition is as follows: under a CfD with a negative price interruption clause, the nuclear operator faces a muted price signal during periods of high demand but retains full exposure to negative prices during periods of excess supply. When output flexibility is limited, the operator must balance output reductions during low-price periods with sufficient capacity to produce during high-price intervals. However, since the CfD strike price is, by design, set below peak market prices — otherwise it would represent a net subsidy rather than a risk-hedging mechanism — the signal provided by high prices is dampened. This distortion leads to suboptimal behaviour: in anticipation of very low or negative prices in future periods, the nuclear operator may strategically reduce output even when demand and prices are high, in order to preserve flexibility for curtailing production later and avoiding losses.

If the operator acts strategically, this effect is compounded. By internalising their impact on market prices, the operator has an additional incentive to withhold output in high-price periods, as doing so elevates prices and improves their overall payoff under the CfD scheme. As a result, total nuclear production falls short of the first-best dispatch, and the system fails to fully respond to signals of scarcity.

4.5. CfD with average reference price

Some authors have argued that the average of the reference price could be used instead of the fluctuating hourly spot price, helping to align better the private incentive and the social outcome (European University Institute. Robert Schuman Centre for Advanced Studies., 2024). The average can be considered on any given temporal interval, from day to year. The profit function of an NPP operating under this rule in our two-period model is

$$\Pi_{\text{Av}} = (p_1 - c)q_1 + (p_2 - c)q_2 + (s - \frac{p_1 + p_2}{2})(q_1 + q_2). \tag{13}$$

Proposition 2. *Under the given assumptions and considering our two-stage model, a nuclear operator under a CfD with average reference price produces at nameplate capacity in time 2 regardless of the situation on the wholesale market, and nuclear overproduces compared to the optimum dispatch.*

Proof is given in Appendix B. The result stems from the fact that under this CfD design, the nuclear operator gets paid a premium for each kWh produced (the $s - \bar{p}$ term, with $\bar{p}$ the average price). This distorts the market price signal and incentivizes the NPP to increase production up to an undesirable extent.

4.6. Capability CfD

This CfD design lets the NPP face the wholesale price and regularly pays the nuclear operator a fixed amount, regardless of actual generation. A clawback payment from the nuclear operator to the State then occurs that equals the ribbon of generation the two parties agreed on to trade beforehand. Let the reference profile be constant at Q for both periods, and let p_t denote the spot price at time t. The marginal cost of nuclear generation is c, and the strike price is s. Under a Capability CfD with symmetric clawback, the operator receives a fixed payment sQ in each period, but must pay back the full market value of a reference generation profile (here assumed constant at Q) regardless of the price level. In parallel, the operator sells its actual output q_t on the spot market and pays its production costs. Its profit is therefore:

$$\Pi_{\text{Cap}} = \sum_t (p_t - c)q_t + (s - p_t)Q.$$

Proposition 3. *A Capability CfD for nuclear yields the same dispatch incentive as a forward contract.*

Proof. We compare the profit functions under a forward contract and under a Capability CfD with symmetric clawback. Under a forward contract, the operator is committed to delivering a fixed quantity Q in each period at a strike price s. The operator can either produce part of this quantity ($q_t \leq Q$) or purchase the remainder ($Q - q_t$) from the market at the spot price p_t. Its production incurs a unit cost c, and the cost of fulfilling the forward obligation is $\text{Cost} = cq_t + (Q - q_t)p_t$. The revenue from the forward contract at each period is sQ. The operator's profit for the whole period under scope is thus:

$$\Pi_{\text{fwd}} = \sum_t sQ - cq_t - (Q - q_t)p_t = \sum_t (p_t - c)q_t + (s - p_t)Q.$$

The profit expressions under both mechanisms are identical which implies the same dispatch incentives for the nuclear operator in each period. □

This CfD design thus mirrors a forward contract but can theoretically span the entire lifetime of the asset, while forwards generally do not extend more than 3-5 years on the electricity market, due to the market failures we formerly identified in Section 3.1 (Schlecht et al., 2024). Forward contracts have been proven to restore incentive to optimal dispatch and to reduce the incentive to exert market power on the spot market (Allaz & Vila, 1993). However, we show that under the assumption of imperfect flexibility, this result does not hold anymore and that the Capability CfD design, as well as a forward contract, distort short-term dispatch.

Proposition 4. *Under the given assumptions and considering our two-stage model, a nuclear operator under a Capability CfD produces at nameplate capacity in time 2 if and only if*

$$a \geq 2bQ - bL + 2c = a^*_{Cap} < a^*_{PC},$$

and nuclear overproduces compared to the optimum dispatch.

Proof is given in Appendix 4.6. As shown in Proposition 3, a Capability CfD can be made equivalent to a forward contract in terms of dispatch incentives. This result reinforces the interpretation of Capability CfDs in the literature as the most incentive-compatible design among CfDs. However, our findings also reveal that even this idealised contract structure leads to dispatch inefficiencies when applied to technologies with limited operational flexibility. Crucially, the equivalence implies that these distortions are not specific to Capability CfDs, but extend to forward contracts themselves. This challenges the conventional view that forwards restore first-best dispatch incentives, and highlights the need to explicitly account for technological constraints when evaluating market design instruments.

5. Numerical model

Using a simple two-period analytical model, we have shown how every CfD design yields a distortion compared to the optimal dispatch. In order to elicit these effects better and to compare them on a representative – even though stylized – case, we now perform a numerical analysis of the CfD designs under scope.

5.1. Methodology

We develop a numerical partial equilibrium model to apply our analytical framework to a stylised case study. The model features a monopolistic nuclear operator competing against a price-taking fringe that owns all other generation technologies. This modelling choice is motivated by three main considerations.

First, from a theoretical standpoint, this structure aligns with the principle of parsimony (Occam's razor). Our objective is to isolate and analyse the effects of different CfD designs on the strategic behaviour of the nuclear operator, rather than to reproduce a specific market configuration. Treating the remainder of the market as a competitive fringe limits the number of auxiliary assumptions required and allows us to focus exclusively on the nuclear operator's dispatch decisions. Bilevel modelling is well suited to this objective, as established in the equilibrium modelling literature (Devine & Siddiqui, 2023).

Second, the bilevel formulation offers important computational advantages over an oligopolistic model. In particular, it enables the inclusion of binary variables in the nuclear operator's objective function — critical for capturing behavioural discontinuities between periods with non-negative and negative prices. Incorporating such binary logic within an oligopolistic setting would significantly complicate the formulation, as the resulting system of KKT conditions becomes non-convex and computationally intractable.

Third, our modelling assumption reflects, to a reasonable extent, the actual market structure in Central Western Europe (CWE), where the vast majority of nuclear capacity is controlled by a single operator—Électricité de France (EDF)—which effectively acts as a dominant firm in this segment of the market. The bilevel problem thus reads

$$\max_{q_t^n} \quad \Pi(q_t^n) \tag{14}$$

$$\text{s.t.} \quad q^n_{min} \leq q^n_t \leq q^n_{max} \quad \forall t \tag{15}$$

$$\sum_t |q^n_{t+1} - q^n_t| \leq L \tag{16}$$

$$\max_{q_t^k, s_t, d_t} \sum_t d_t \left(a_t - \frac{bd_t}{2} \right) - q_t^g \left(e + \frac{f q_t^g}{2} \right) - c q_t^n \tag{17}$$

$$\text{s.t.} \quad d_t - \sum_k q_t^k = 0 \quad \forall t \quad (p_t) \tag{18}$$

$$0 \leq q_t^k \leq q^k_{max} \quad \forall t, k \quad (\rho_t^k, \mu_t^k) \tag{19}$$

$$s_{t+1} - s_t - \eta q_t^{s,+} + q_t^{s,-} = 0 \quad \forall t < T \quad (\nu_t) \tag{20}$$

$$0 \leq s_t \leq S^{max} \quad \forall t \quad (\rho_t^s, \mu_t^s) \tag{21}$$

$$d_t \geq 0 \quad \forall t. \tag{22}$$

We denote electricity generation from technology k at time t by q_t^k. Generation from hydropower and biomass is treated as exogenous and fixed. Nuclear generation (n) is determined endogenously at the upper level, while all other technologies — including gas turbines (g), storage, and renewables — are dispatched at the lower level by an Independent System Operator (ISO). The ISO is modelled as a welfare-maximising agent, analogous to the Euphemia market-clearing algorithm used in European day-ahead electricity markets (Papavasiliou & Smeers, 2017). This formulation mirrors the behaviour of a competitive fringe, where the ISO clears the market based on supply offers and demand bids.

The inverse demand function is assumed to be linear, of the form $p_t = a_t - bd_t$, where p_t denotes the electricity price, d_t total demand at time t, and a_t, b are exogenous parameters calibrated from historical data. The slope b is chosen such that the implied price elasticity of demand at the calibration point corresponds to $\varepsilon = -0.05$, consistent with empirical estimates (Hirth et al., 2024).

Gas turbines are aggregated into a single representative technology. To account for heterogeneity in plant efficiencies, we model their variable costs using a linearly increasing marginal cost function, $e + f q_t^g$, where q_t^g is the total generation from gas at time t. This approach reflects the increasing marginal cost structure as more efficient units are dispatched first.

Storage units (s) are modelled with dynamic intertemporal constraints, which ensure consistency in the filling level of storage across periods. Specifically, the state-of-charge evolves according to standard energy balance equations, accounting for round-trip efficiency and charging/discharging limits.

The model is formulated as a Mathematical Program with Equilibrium Constraints (MPEC), in which the lower-level welfare-maximising dispatch problem is replaced by its Karush-Kuhn-Tucker (KKT) conditions (Gabriel et al., 2012). The resulting MPEC is subsequently reformulated as a Mixed-Integer Quadratically Constrained Program (MIQCP). Complementarity conditions arising from the KKT system are encoded using the Big-M method, which introduces binary variables to enforce the required logic.

The profit function of the nuclear operator, $\Pi(q_t^n)$, depends on the specific CfD scheme under consideration. A detailed description of the various designs is provided in Section 4. Among the different CfD structures, the CfD with a negative-price interruption clause requires additional modelling effort. Since the payout is contingent on prices being non-negative — a condition that is binary and inherently non-convex — its implementation requires the use of binary variables. This technical feature is one of the motivations for choosing the MPEC framework over alternative formulations such as Mixed Complementarity Problems (MCPs).

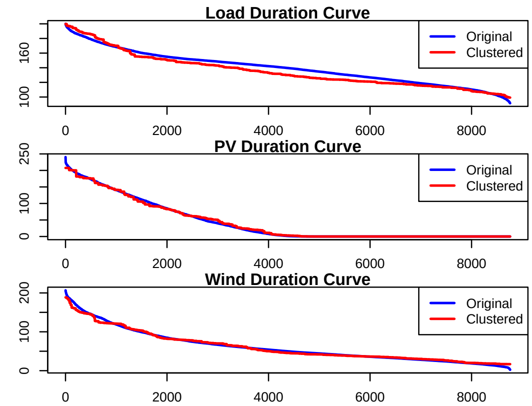
In some cases, the objective function involves bilinear terms, such as the product of market price and nuclear generation. This occurs, for example, under the Capability CfD and the CfD with an average reference price. The Gurobi solver is capable of handling such bilinearities by enumerating over local optima and selecting the global optimum within a specified confidence threshold.

A detailed explanation of the model resolution, including the exact MPEC-to-MIQCP transformation and implementation details, is provided in Appendix D.

5.2. Calibration

We consider the Central Western Europe (CWE) region, comprising France, Belgium, the Netherlands, and Germany in 2040, as displayed in Figure 2b. We choose the year 2040 as national official targets (either directly from government bodies or prospective works from TSOs) are available for this horizon, and the new nuclear buildout is projected to materialize around this time horizon. The numerical model is run on a set of 10 representative days, each composed of 12 2-hour blocks. Figure 2a displays the approximation of the load duration curve we obtain after the clustering process is done, based on a k-medoids clustering approach (Poncelet et al., 2017).

Table 1 presents the key assumptions regarding power generation capacities used in the model. Generation from must-run technologies — namely hydropower and biomass—is treated as exogenous and derived directly from historical time series data.



(a) Approximation of load, PV and Wind time series based on 10 representative days

(b) The Central Western Europe region under scope

Figure 2: Time and spatial aggregation used in the model

The supply function for gas-fired power plants is calibrated using the EWI Merit Order Tool developed by the University of Cologne.[5] We assume a carbon price of €150/ton and maintain the current shape of the gas supply curve for the 2040 horizon. This approach reflects the assumption that the relative cost ranking and marginal cost distribution across gas technologies remain stable over time, conditional on the carbon price scenario.

For all dispatchable generation technologies — nuclear power plants (NPPs), gas turbines, and hydropower — generation is constrained by their respective installed capacities, adjusted by technology-specific derating factors to reflect historical availability patterns. Nuclear flexibility is considered to be twice of the current average flexibility of French NPPs. To set a daily scale limit on nuclear flexibility, we extract the nuclear flexibility practice of the French fleet from historical data. We then perform a clustering on the French nuclear fleet generation pattern and extract the variation in output from the cluster that shows the maximum intraday variation in output, which we multiply by 2 (there is theoretically room for improving French nuclear flexibility, although to an extent that remains uncertain) to set our maximum flexibility potential for each of our 10 representative days. The result from the clustering is displayed in Figure 3. The model includes both pumped hydro storage (PHS) and chemical batteries, acknowledging the expected rapid scale-up of battery storage technologies in future electricity systems.

Finally, due to computational constraints, we adopt a copper plate assumption,

[5]EWI website

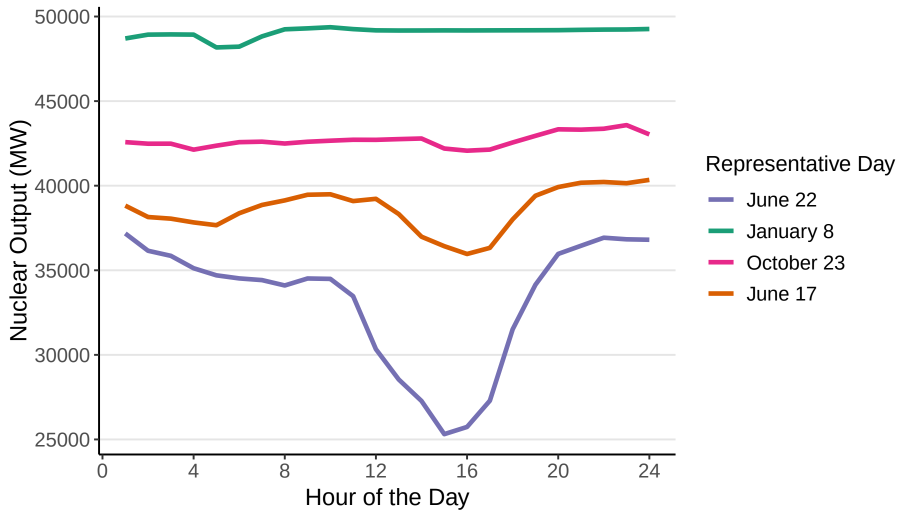


Figure 3: Representative daily nuclear generation in France (2024)

abstracting from transmission constraints and assuming a perfectly integrated market without internal network bottlenecks.

Region & Variable cost	France	Installed capacity (GW) Germany	Belgium	Netherlands	Var. Cost (€/MWh)
Nuclear			40		10
Gas			90		110-380
Onshore Wind	49	82	8	7	0
Offshore Wind	20	34	8	23	0
Solar	60	200	22	46	0
Storage			30		5

Table 1: Assumption on installed capacity and variable costs

VRE production time series are generated using data on load factor from the Renewables.ninja platform (Pfenninger & Staffell, 2016). The time series of each country is then aggregated together to simulate the renewable production for the whole CWE area.

5.3. Cases under study

We compare the dispatch obtained for 6 different cases: (i) a perfect competition case that serves as a benchmark for optimal dispatch (PC), (ii) a Stackelberg equilibrium where the nuclear producer is fully exposed to wholesale prices and can exert market power (Stackelberg, also used as a benchmark for the worst-case dispatch scenario) (iii) a classical CfD with payment proportional to the cumulated generation (CfD), (iv) a CfD with negative-price interruption (Neg CfD), (v) a CfD with the average of the spot price as reference (Av CfD) and (vi) a Non-production based CfD, that we refer to as Capability CfD (Cap CfD). We consider a common strike price value for every CfD design of €100/MWh. This choice is backed by evidence from past contracts on CfD for nuclear generation, such as the Hinkley Point C case, where the strike price parties agreed upon has been set close to this level (£92/MWh, 2012 price).

6. Results

From the 10 representative days extracted from the clustering process, one is of specific interest to our concern as it represents a typical spring/summer day, characterized by a massive PV generation around noon and a need for the generation to take over during shoulder hours — i.e., the morning and evening net load peaks. This representative day weighs 20% of the year (the corresponding medoïd accounts for 70 days out of the 365 used in the clustering), which shows it is a situation that will be very common in future power markets as PV capacity grows. In the following, we propose to show results for this specific day as it stresses the point made in Section 4 about the potential misuse of nuclear in situations of very low prices, followed by soaring prices in the evening peak. Results concerning the overall year will also be presented thereafter.

6.1. Nuclear Dispatch

The nuclear hourly dispatch is highly impacted by the remuneration scheme under scope. We first analyze the dispatch decision under perfect competition. In that scenario, the ability of nuclear to generate power in moments of high market prices is fully utilized, and the nuclear generation is set at nameplate capacity in such periods. With limited nuclear flexibility, the output cannot reach the minimum allowed output power in moments where downward flexibility is needed, but plateaus at an intermediary value. Figure 4 presents the results for the typical spring/summer day under scope. Flexibility is very much needed due to the collapse of solar production after 5 pm, which is hardly compensated by wind and storage, necessitating the use of gas plants, resulting in market prices soaring rapidly from low-to-negative levels mid-day to more than €130/MWh a few hours later.

In the classical CfD case, where the nuclear operator is paid proportionally to production regardless of market conditions, the NPPs maximize production at every time step, resulting in a ribbon of production spanning the entire day. Here, the partial ability of nuclear to run flexibly is mothballed, which results in very low negative prices during the day (see Section 6.2). However, as nuclear energy maximizes output, the periods of energy scarcity are handled similarly to the PC case, and production levels in shoulder hours are maximized. Also, the complete isolation of the NPPs from the market mutes any incentive to exert market power and strategic withholding.

The CfD with negative-price interruption and the Stackelberg scenarios yield similar results for this specific day, displaying the lowest nuclear generation. Although it is not surprising for the Stackelberg equilibrium, the CfD approach is generally presented as a way to restore dispatch optimality from the classical CfD case since the nuclear operator faces the market prices when the latter goes negative, incentivizing it to harvest its flexibility potential to lower production in these moments. One could then anticipate the nuclear dispatch under CfD with negative-price interruption to lie close to the optimal dispatch obtained in the PC case, but this is not what we observe. Indeed, in that situation, we already showed in Section 3 that nuclear has the incentive to reduce output in periods of high prices to be capable of lowering generation around noon when they are exposed to the wholesale price and can lower their profit loss by producing little energy. This result is undesirable as nuclear operators prioritize lower production in moments of low prices compared to maximizing production when prices spike.

In line with our analytical insights from section 4, we find the Average CfD to overproduce compared to the first-best solution. The Capability CfD is the design that aligns more closely to the optimal outcome. However, and in line with our analytical findings of Section 4.6, even this CfD design misaligns dispatch incentives due to the partial flexibility of nuclear, and the latter underproduces compared to the first-best competitive outcome.

6.2. Market Prices

For the same representative day, we compute the price level based on the CfD design. Table 2 shows the results, as well as the results for the whole year, composed of 10 representative days. The wide diversity of dispatch patterns across the studied cases translates to the simulated market prices that show vastly different trends. The difference is even more striking when considering the single represen-

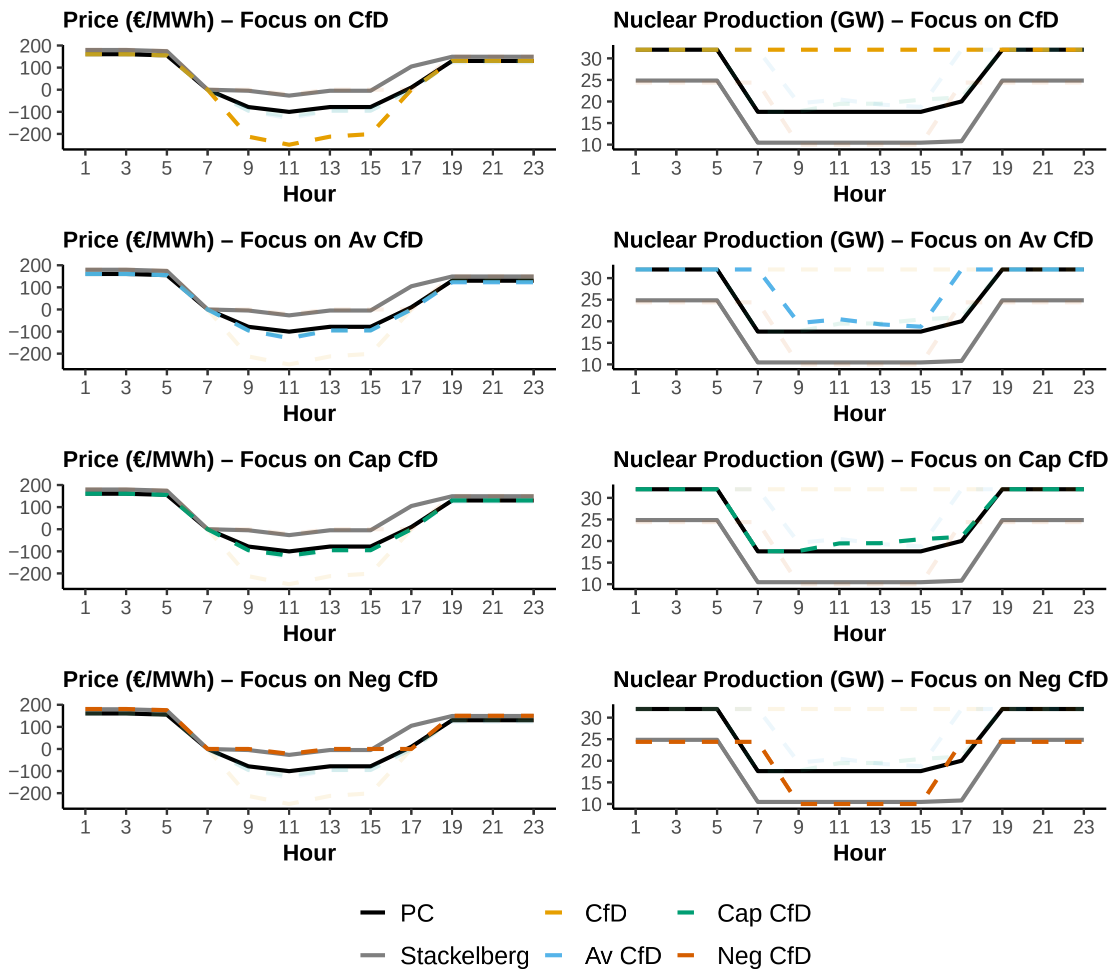


Figure 4: Wholesale prices and nuclear generation for a representative summer day depending on the CfD design

tative spring/summer day: prices can vary widely depending on the CfD design, with an average of approximately €0/MWh in the CfD case and a maximum of €87/MWh for the Stackelberg equilibrium. Interestingly, the CfD with negative price interruption yields a very similar outcome to the Stackelberg case, where the nuclear operator fully faces wholesale market prices and has the latitude to strategically withhold generation to inflate prices to their advantage. This is a direct consequence of the tradeoff nuclear operators face on such a day due to their limited operational flexibility, and brings concerns relative to the market outcomes that such a CfD design can yield. The simulation results reveal that the CfD with negative-price interruption performs relatively well when outcomes are aggregated over the entire year. The sharp flexibility challenges observed during spring and summer — driven by low demand and high renewable output — are less prominent when viewed at an annual level. Notably, both the Negative-Price CfD and the Capability CfD lead to average electricity prices that are relatively close to the first-best benchmark. However, there is a clear distinction between the two: the Capability CfD yields a lower average price, while the CfD with negative-price interruption results in a higher one. The difference in average price between the two designs reaches approximately 13%, signalling important trade-offs. These findings suggest that policy-makers must weigh the relative importance of consumer surplus versus producer surplus in the choice of remuneration scheme. A more detailed welfare analysis is provided in the following section.

Scenario	PC	Stackelberg	Cap CfD	Neg CfD	CfD	Av CfD
Summer Day						
Mean Price (€/MWh)	45.0	87.1	38.5	80.5	-0.7	35.9
Full-year						
Mean Price (€/MWh)	61.1	87.1	57.5	65.6	42.8	49.8

Table 2: Summary statistics from the numerical model.

As expected, the lowest average market price is observed under the classical CfD, at €42.8/MWh. At the other end of the spectrum, the Stackelberg scenario (only presented here as a benchmark for comparison) results in the highest average price, reaching €87/MWh. The Average-Price CfD scenario produces intermediate outcomes. It is characterised by overall nuclear overproduction, which raises potential concerns about the financial sustainability of renewable generators and the erosion of surplus for other market participants.

These differences become more pronounced during critical periods. For example, during summer days with large solar output, the CfD with negative-price interruption leads to significantly lower nuclear output compared to the PC scenario—by up to 23%—which drives price spikes of over +78% in evening hours. These dynamics, though limited to roughly 20% of the year, suggest that the timing of market distortions—rather than their annualised magnitude—may be a key factor when evaluating CfD design performance.

From a policy perspective, these results underscore the inherent trade-offs. The Classical CfD maximises short-term consumer surplus and delivers the lowest market prices (€42.8/MWh on average), but at the expense of system-wide efficiency, producer viability, and future investment incentives. On the other hand, the Capability CfD and Negative-Price CfD maintain more balanced outcomes, preserving investment signals while limiting inefficiencies and excess costs.

6.3. Impact on welfare

We intend to draw a comparative analysis of the social desirability of these various market outcomes. The consumer surplus, producer surplus, and total welfare are extracted from the three cases under scope and are presented below in Table 3. The subsidy cost is displayed to compare the different CfD designs on the cost level for public finances. Table 3 presents the breakdown of welfare outcomes across

Scenario	PC	Stackelberg	Cap CfD	Neg CfD	CfD	Av CfD
Consumer surplus	1	-4.48%	+0.67%	-1.05%	+2.98%	+1.5%
Producer surplus	1	+71.94%	+21.33%	+33.58%	-13.91%	+8.36%
Total welfare	1	-0.25%	-1.83%	-1.13%	-2.67%	-1.93%

Table 3: Comparison of welfare statistics for the whole year.

scenarios. The decrease in total welfare (net of the subsidy's cost) for the different cases of CfD design can reach 2.67% in the case of a classical CfD. This is driven by a massive cost for financing the subsidy, as the price is regularly well below zero with this design: NPPs are incentivized to produce at nameplate capacity, whatever the market situation. With this suboptimal CfD design, consumers' raw surplus is increased by almost 3% due to the sharp decline in market prices. However, assuming the integrality of the subsidy is financed by electricity consumers through their retail tariffs, the increase in consumer surplus becomes negligible: the reduction in wholesale prices is outweighed by the increase in taxes. Producers' surplus is cut by approximately 14% due to depressed prices compared to the first-best outcome.

The CfD with negative-price interruption offers the best overall situation in terms of total welfare. Producer surplus increases by +33.58% relative to PC, while reducing consumer surplus by 1.05%, which ultimately yields a total welfare loss of

-1.13%. The mechanism prevents nuclear overproduction in low-price or negative-price hours, which stabilises prices and improves efficiency compared to the Classical CfD. However, this design yields the highest loss in consumer surplus among all CfD designs. We unfolded the reason behind that in section 4: the CfD with negative-price interruption incentivizes the nuclear operator to lower its output in the moment of negative prices. However, as NPPs are only partially flexible, this prevents them from producing at nameplate capacity in subsequent hours of high net demand (when the PV output falls). The consequence is a rise in average prices and a loss of consumer surplus.

The Capability CfD performs better than Negative-Price CfD in that regard, with a raw consumer surplus increase of 0.67% and a slightly smaller producer surplus gain of +21.33%. This is aligned with the theory that predicts better market behavior with this CfD, which mirrors a forward contract. The cost of the subsidy can, however, be detrimental to this design. Indeed, with this scheme, the State agrees to pay the nameplate capacity to the nuclear operator at a price (here, €100/MWh) that exceeds the average market price.

The Average CfD design occupies a middle ground: it boosts producer surplus by 8.36%, raw consumer surplus by 1.5%, and reduces total welfare by 1.93%. This CfD design results in moderate overproduction by nuclear, which may again jeopardise VRE project revenues.

The Stackelberg case, where the nuclear operator acts strategically without constraints, is also presented as a benchmark for comparison. Here, it yields a sharp increase in producer surplus, rising by +72% compared to the PC case. This comes at a significant cost to consumers, whose surplus drops by -4.48%. Due to the low elasticity of electricity demand, the bulk of the change in welfare is due to this waterbed effect between consumer and producer surplus, and total welfare drops only slightly (-0.26%).

Finally, Table 4 reports the public cost of subsidising nuclear under the various CfD designs. The Classical CfD entails the highest fiscal burden, with a net cost of €844 million per year, followed by the Average CfD (€690 million) and the Capability CfD (€662 million). In contrast, the Negative-Price CfD cuts the cost nearly in half, down to €348 million per year. This highlights the fiscal sensitivity of subsidy schemes to design details. This result shows two caveats that are worth noting. First, we assume a common strike price of €100/MWh, whatever the CfD design. However, the different CfD options bring different levels of risks for investors. The classical CfD typically embodies low amounts of risk as both the selling price (the strike) and the volume are secured. Moreover, under this design, the nuclear operator does not have to pay during the periods when the plant is unavailable (for planned mainte-

Scenario	Subsidy cost (M€/year)
CfD	844
Av CfD	690
Cap CfD	662
Neg CfD	348

Table 4: Net subsidy cost depending on the CfD design, for a strike price of €100/MWh

nance work or unplanned issues). This is, for instance, not the case for the Capability CfD, where the nuclear operator has to pay the clawback term to the government, regardless of the situation of the plant. Theoretically, investors would incorporate these differences in the level of risk and include them in their bid, yielding different strike prices for different CfD designs. Second, the cost for the Negative-Price CfD is calculated under the assumption that payments are interrupted during negative-price hours. Should payments remain active, albeit decoupled from real-time production, the cost would increase substantially up to the cost of the Classical CfD case.

6.4. Sensitivity to VRE curtailment flexibility

The baseline simulations in this study assume that a substantial portion of VRE production is non-curtailable. This reflects current market conditions, where legacy feed-in tariffs and CfD schemes continue to incentivise VRE output even when prices are negative. However, the long-term outlook for VRE remuneration is changing. New installations are increasingly exposed to wholesale market signals, whether through merchant models, PPAs, or modern CfDs that include negative-price clauses. These evolving arrangements are expected to reduce the incentive to produce during surplus conditions, enabling greater curtailment of VRE output. In the limit, this could eliminate negative prices altogether.

To test the sensitivity of our results to this structural assumption, we model a scenario in which all VRE production is perfectly curtailable. This implies that any excess supply can be resolved through renewable curtailment without pushing prices into negative territory. While idealized, this case offers insights into the long-run performance of nuclear support schemes under a high-VRE system operating without negative prices. The welfare impacts of this scenario are shown in Table 5. As expected, eliminating negative prices has a levelling effect on several CfD designs. Specifically, the Classical CfD and the CfD with negative-price interruption yield identical dispatch outcomes for the nuclear operator. Since negative prices no longer occur, the interruption clause in the latter is never activated, and both mechanisms lead to full output at nameplate capacity across all hours. In this configuration,

Scenario	PC	Stackelberg	Cap CfD	Neg CfD	CfD	Av CfD
Whole Year						
Consumer surplus	0%	-2.93%	+0.4%	+0.42%	+0.42%	+0.52%
Producer surplus	0%	+38.04%	+15.52%	+14.27%	+14.27%	+14.04%
Total welfare	0%	-0.12%	-1.43%	-1.51%	-1.51%	-1.45%

Table 5: Welfare impact of the different CfD designs in a case without constraints on VRE curtailment.

nuclear plants behave as baseload generators with no incentive to adjust to intraday price variation.

By contrast, the Capability CfD and the Average CfD still provide a form of market responsiveness. These mechanisms tie remuneration to prevailing or averaged market conditions, which introduces an incentive for the nuclear operator to modulate output in moments of null prices. This results in improved allocative efficiency and explains why these two designs perform better in terms of total welfare.

Producer surplus remains elevated under all CfD schemes, ranging from +14.04% to +15.52%, and raw consumer surplus shows a small increase. The Stackelberg benchmark, in which the nuclear operator behaves purely strategically without contractual constraints, produces the most extreme distributional effects, with a +38.04% rise in producer surplus and a nearly 3% drop in consumer surplus.

Finally, Table 6 reports the net annual subsidy cost under each CfD design in the no-curtailment constraint case. Across all schemes, subsidy expenditures converge at approximately €260 million per year for a strike price of €100/MWh. The full

Scenario	Subsidy cost (M€/year)
CfD	522
Av CfD	526
Cap CfD	520
Neg CfD	522

Table 6: Net subsidy cost depending on the CfD design, for a strike price of €100/MWh and no curtailment constraint on VREs

flexibility to curtail VRE illustrates a potential future system where negative prices are rare or absent. In such a setting, the differences in nuclear behaviour across CfD designs diminish, but flexible remuneration mechanisms such as the Capability CfD and Average CfD continue to outperform rigid contracts in terms of overall welfare and dispatch efficiency. This reinforces the case for more dynamic nuclear support designs in future high-renewable electricity systems.

6.5. Partial CfD coverage: effects on prices and welfare

In practice, CfDs are unlikely to be applied to the full nameplate capacity of an NPP. There are both economic and policy rationales for limiting the share of production covered by such contracts. From a policy standpoint, governments may wish to moderate public expenditure by reducing the volume of production subsidized under CfDs. Meanwhile, nuclear operators may seek to preserve opportunities for market arbitrage. The academic literature also raises concerns that full-coverage CfDs may inadvertently reduce market liquidity. When the entire output is insulated from price fluctuations via a fixed strike price, producers have little incentive to participate in forward markets, weakening market-based hedging mechanisms for the whole industry (with less liquidity, it becomes more difficult for any retailer to buy electricity years ahead at a fair price). Partial coverage mitigates this effect, allowing some exposure to market signals and maintaining a role for long-term contracting.

To reflect this more realistic setting, we simulate a scenario in which only 50% of the nuclear plant's capacity is covered by a CfD. The remaining capacity is split between forward contracts (40%), and real-time spot market (10%). The results are presented in Table 7, which compares electricity prices for a representative summer day and on an annual basis across the various CfD designs. The observed price differences are less pronounced than in the full-coverage case, reflecting the dilution of contract-induced distortions. Nonetheless, a meaningful distinction remains between two groups of CfD designs. The first group includes the Capability CfD and the CfD

Scenario	PC	Cap CfD	Neg CfD	CfD	Av CfD
Summer Day					
Mean Price (€/MWh)	45.0	40.6	44.2	24.1	36.2
Full-year					
Mean Price (€/MWh)	61.1	59.0	60.1	54.6	57.4

Table 7: Price for a representative summer day and the whole year in a case with only 50% of production covered by the CfD.

with negative-price interruption. These designs yield electricity prices close to the PC benchmark. In particular, the Negative-Price CfD no longer causes overproduction in negative-price hours, as shown in Section 4.4. By limiting CfD coverage, a larger share of nuclear output remains sensitive to market signals, thereby encouraging more efficient dispatch decisions. This partial exposure effectively neutralises the perverse incentives that previously inflated prices during high-demand hours and depressed them during surplus periods.

The second group, comprising the Classical CfD and the Average CfD, continues to produce significant price suppression. On the summer day, the Classical CfD results in an average price of only €24.1/MWh, almost half the PC level. Annual prices are also substantially lower, at €54.6/MWh. These outcomes indicate that even with limited coverage, the fixed-price incentive of the Classical CfD remains strong enough to distort dispatch behaviour and reduce price signals, with implications for both market efficiency and investment incentives in other technologies.

These differences are also reflected in the welfare impacts presented in Table 8. With only 50% of production covered by CfDs, the divergence in welfare outcomes across designs narrows considerably. Nonetheless, the distribution of surplus between consumers and producers remains a key point of differentiation. Under the Capability CfD, producer surplus increases by +22.62%, and raw consumer surplus increases by 0.34%. The CfD with negative-price interruption results in a slightly more balanced distribution, with a +17.69% gain for producers and a −0.21% raw gain for consumers.

Scenario	PC	Cap CfD	Neg CfD	CfD	Av CfD
Consumer surplus	1	+0.34%	+0.21%	+1.21%	+0.70%
Producer surplus	1	+22.62%	+17.69%	+9.19%	+17.39%
Total welfare	1	-0.88%	-0.51%	-1.1%	-0.85%

Table 8: Welfare impact of the different CfD designs in a case with only 50% of production covered by the CfD.

Partial CfD coverage thus significantly mitigates the distortions observed in the full-coverage case. Designs that incorporate price-responsiveness — such as the Capability CfD and the Negative-Price CfD — prove particularly robust under this more realistic policy structure. Flat CfD designs continue to exert downward pressure, although to a lower extent than compared to a full-coverage situation.

7. Conclusion

This paper evaluates how alternative Contract-for-Difference (CfD) designs affect the short-term dispatch incentives of nuclear power plants (NPPs). While CfDs are increasingly used to de-risk investment in low-carbon generation, including nuclear, they distort operational behaviour by decoupling revenues from market signals. This misalignment is especially problematic for technologies that have potential for operational flexibility, such as nuclear.

We investigate several CfD designs—including the widely used classical CfD, a version with negative-price interruption, an average-price CfD, and a Capability CfD that mirrors forward contracting. We provide an analytical framework to investigate the impact of these different design options on a stylized case, and then build a numerical partial equilibrium model calibrated on the Central Western European market in 2040. Our results show that different CfD designs yield very contrasting market outcomes, resulting in a significant impact on prices and welfare. Although none of the CfDs fully restores optimal dispatch incentives when considering nuclear-specific flexibility constraints, some behave better than others.

Classical CfDs incentivise overproduction during low-price periods, depressing market prices and generating high subsidy costs. The average-price CfD reduces this distortion but still leads to excess output. The negative-price interruption design partially mitigates overproduction by suspending payments in negative price periods, but can perversely encourage underproduction during system stress. This is because operators seek to avoid losses in moments of negative prices by lowering production, but lack the flexibility to ramp up thereafter during the evening peak. As a consequence, the consumers' surplus shrinks under such a CfD design compared to the optimal market outcome, even without considering the cost of the subsidy. The Capability CfD, which delinks remuneration from output, can result in slight overproduction if the nuclear operator acknowledges their market power potential, but preserves a better tradeoff between consumers' and producers' change in surplus.

From a policymaking perspective, our findings underscore a fundamental tradeoff: CfDs may help lower financing costs for nuclear investments, but reduce allocative efficiency in the short term. The choice of CfD design, therefore, involves balancing investment incentives with efficient market outcomes and managing distributional effects between producers and consumers. Designs that preserve price responsiveness, such as the Capability or negative-price CfD, may better serve long-term system efficiency.

Future research should extend this analysis to include endogenous investment decisions considering risks. Indeed, a blind spot of this paper is the process through which the strike price of the CfD is settled. Different CfD designs propose different exposures to risk, and theory predicts this would be incorporated into the level of the strike price. Given the oligopolistic nature of the nuclear industry (very few vendors exist), tenders may be inefficient in disclosing information to the regulator.

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Appendix A. CfD with negative-price interruption

Proof. A nuclear operator under a CfD with negative-price interruption solves the following two-stage profit-maximization problem:

$$\begin{aligned} \max_{q_1,q_2} \quad & (p_1 - c)q_1 + (s-c)q_2 \\ s.t. \quad & q_2 - q_1 \leq Q \quad (\nu) \\ & q_{1,2} \leq Q \quad (\mu_1, \mu_2) \\ & q_{1,2} \geq 0 \quad (\rho_1, \rho_2) \end{aligned}$$

with s the strike price. The price is set in 1 by $p_1 = -bq_1$ and in time 2 by $p_2 = a - bq_2$ (see Figure 1), and the nuclear operator incorporates the impact of their dispatch decision on price formation. The Lagrangian writes

$$\mathcal{L} = (-bq_1 - c)q_1 + (s-c)q_2 - \nu(q_2 - q_1 - L) - \mu_1(q_1 - Q) - \mu_2(q_2 - Q),$$

and the KKTs read

$$0 \leq 2bq_1 + c - \nu + \mu_1 \perp q_1 \geq 0 \tag{A.1}$$
$$0 \leq -s + c + \nu + \mu_2 \perp q_2 \geq 0 \tag{A.2}$$
$$0 \leq -q_2 + q_1 + L \perp \nu \geq 0 \tag{A.3}$$
$$0 \leq -q_1 + Q \perp \mu_1 \geq 0 \tag{A.4}$$
$$0 \leq -q_2 + Q \perp \mu_2 \geq 0. \tag{A.5}$$
$$\tag{A.6}$$

Following the same argument as in Section 4.1, we have $\mu_1 = 0$ and the flexibility constraint is saturated, giving $q_2 = q_1 + L$, and $\nu > 0$. To have $q_2 = Q$ and $q_1 = Q - L$ we write from (A.1)-(A.2)

$$\begin{cases} 2b(Q-L) + c = \nu \\ 2c - s + 2bQ - 2bL + \mu_2 = 0 \end{cases}$$

which yields $\mu_2 = s - 2c - 2bQ + 2bL \geq 0$, which ultimately means that in order to have $q_2 = Q$ we must have (by the same proof by contradiction as in Section 4.1) $s^* \geq 2bQ - 2bL + 2c$. When comparing this condition on s with the level of price we find in Section 4.1, which was $p_2^{PC} = bQ - bL + 2c$, we find $s^* - p_2^{PC} = b(Q-L) > 0$. Thus, we showed that the CfD with negative-price interruption yields a lower nuclear generation than the first-best solution, as the strike price needed to make it produce at nameplate capacity in time 2 is higher than the market price that makes the nuclear operator produce at nameplate in the PC case. □

Appendix B. Average CfD

Proof. A nuclear operator under a CfD with an average of the wholesale price as reference solves the following two-stage profit-maximization problem:

$$\begin{aligned}
\max_{q_1,q_2} \quad & (p_1 - c)q_1 + (p_2 - c)q_2 + (s - \frac{p_1 + p_2}{2})(q_1 + q_2) \\
s.t. \quad & q_2 - q_1 \leq Q \quad (\nu) \\
& q_{1,2} \leq Q \quad (\mu_1, \mu_2) \\
& q_{1,2} \geq 0 \quad (\rho_1, \rho_2).
\end{aligned}$$

Indeed, such a CfD design lets the producer face the market price in every period and pays the difference in revenue the operator would have earned at a strike price of s. The Lagrange function reads

$$\begin{aligned}
\mathcal{L} =& (-bq_1 - c)q_1 + (a - bq_2 - c)q_2 + s(q_1 + q_2) - \frac{1}{2}(a - bq_1 - bq_2)(q_1 + q_2) \\
& - \nu(q_2 - q_1 - L) - \mu_1(q_1 - Q) - \mu_2(q_2 - Q),
\end{aligned}$$

and the KKTs write

$$0 \leq bq_1 - bq_2 + c - s + \frac{a}{2} - \nu + \mu_1 \perp q_1 \geq 0 \tag{B.1}$$
$$0 \leq -a + bq_2 - bq_1 + c - s + \frac{a}{2} + \nu + \mu_2 \perp q_2 \geq 0 \tag{B.2}$$
$$0 \leq -q_2 + q_1 + L \perp \nu \geq 0 \tag{B.3}$$
$$0 \leq -q_1 + Q \perp \mu_1 \geq 0 \tag{B.4}$$
$$0 \leq -q_2 + Q \perp \mu_2 \geq 0. \tag{B.5}$$
$$\tag{B.6}$$

Using the same argument as in Appendix A we know that we have $\mu_1 = 0$. The condition for production at nameplate capacity in 2 $q_2 = Q$ yields, summing (B.1) and (B.2)

$$\mu_2 = 2(s - c) \geq 0,$$

which is always true. Hence, we showed that the CfD with average reference price leads to an overproduction compared to the PC case. □

Appendix C. Capability CfD

Proof. A nuclear operator under a Capability CfD solves the following two-stage profit-maximization problem:

$$\begin{aligned}\max_{q_1,q_2} \quad & (p_1 - c)q_1 + (p_2 - c)q_2 + 2sQ - (p_1 + p_2)Q \\ s.t. \quad & q_2 - q_1 \leq Q \quad (\nu) \\ & q_{1,2} \leq Q \quad (\mu_1, \mu_2) \\ & q_{1,2} \geq 0 \quad (\rho_1, \rho_2).\end{aligned}$$

Indeed, under a Capability CfD the nuclear operator faces the market prices but is paid for the delivery of Q at price s in both periods and should pay back the market revenue of a perfectly flexible plant in both periods. Since the latter does not produce at time 1 due to the fact that the price is lower than the variable cost, the clawback term only applies to period 2. The Lagrange function reads

$$\begin{aligned}\mathcal{L} =& (-bq_1 - c)q_1 + (a - bq_2 - c)q_2 + 2sQ + bq_1Q - aQ + bq_2Q \\ & - \nu(q_2 - q_1 - L) - \mu_1(q_1 - Q) - \mu_2(q_2 - Q),\end{aligned}$$

and the KKTs read

$$0 \leq 2bq_1 + c - bQ - \nu + \mu_1 \perp q_1 \geq 0 \tag{C.1}$$
$$0 \leq -a + 2bq_2 + c - bQ + \nu + \mu_2 \perp q_2 \geq 0 \tag{C.2}$$
$$0 \leq -q_2 + q_1 + L \perp \nu \geq 0 \tag{C.3}$$
$$0 \leq -q_1 + Q \perp \mu_1 \geq 0 \tag{C.4}$$
$$0 \leq -q_2 + Q \perp \mu_2 \geq 0. \tag{C.5}$$
$$\tag{C.6}$$

Again, as we showed in Appendix A, we have $\mu_1 = 0$. The nuclear operator produces at nameplate capacity in 2 ($q_2 = Q$) only if

$$\mu_2 = a - 2bQ + 2bL - 2c \geq 0,$$

which translates to a condition on a:

$$a \geq 2bQ - 2bL + 2c = a^*_{Cap}. \tag{C.7}$$

We compare the minimum value of a that results in producing at nameplate in the case of a Capability CfD, a^*_{Cap}, with the value of a that yields the same result in the PC case, $a^*_{PC} = 2bQ - bL + 2c$:

$$a^*_{Cap} - a^*_{PC} = -bL < 0,$$

And the production under a Capability CfD is higher than in the first-best, PC case, as the y-intercept of the inverse demand function that results in generation at nameplate capacity is lower in the Capability CfD situation than in the PC case. □

Appendix D. Numerical model

By replacing the follower's problem with its KKT conditions, the problem of the leader can then be expressed as

$$
\begin{aligned}
\max_{q_t^{nuc}} \quad & \Pi(q_t^{nuc}) \\
\text{s.t.} \quad & q_{min}^{nuc} \leq q_t^{nuc} \leq Q_{nuc} \quad \forall t && \text{(D.1)} \\
& \sum_t |q_{t+1}^n - q_t^n| \leq L && \text{(D.2)} \\
& \textit{Market clearing} \\
& 0 \leq -a_t + bd_t + p_t \perp d_t \geq 0 \quad \forall t && \text{(D.3)} \\
& d_t - q_t^g - q_t^{PV} - q_t^{wind} - q_t^n - q_t^{hydro,bio} = 0,\ p_t \text{ free}, \quad \forall t && \text{(D.4)} \\
& \textit{PV, Wind, and Gas} \\
& 0 \leq e + fq_t^g - p_t + \mu_t^g \perp q_t^g \geq 0 \quad \forall t && \text{(D.5)} \\
& 0 \leq -q_t^g + q_{max}^g \perp \mu_t^g \geq 0, \quad \forall t && \text{(D.6)} \\
& 0 \leq -q_t^{PV} + q_{max}^{PV} \perp \mu_t^{PV} \geq 0, \quad \forall t && \text{(D.7)} \\
& 0 \leq -q_t^{wind} + q_{max}^{wind} \perp \bar{\mu}_t^{wind} \geq 0, \quad \forall t && \text{(D.8)} \\
& 0 \leq q_t^{PV} - q_{min}^{PV} \perp \rho_t^{PV} \geq 0, \quad \forall t && \text{(D.9)} \\
& 0 \leq q_t^{wind} - q_{min}^{wind} \perp \rho_t^{wind} \geq 0, \quad \forall t && \text{(D.10)} \\
& 0 \leq -p_t + \mu_t^{PV} - \rho_t^{PV} \perp q_t^{PV} \geq 0 \quad \forall t && \text{(D.11)} \\
& 0 \leq -p_t + \mu_t^{wind} - \rho_t^{wind} \perp q_t^{wind} \geq 0 \quad \forall t && \text{(D.12)} \\
& \textit{Storage} \\
& 0 \leq \nu_{t-1} - \nu_t + \mu_{s,t} \perp S_t \geq 0, \quad \forall t > 1 && \text{(D.13)} \\
& 0 \leq c_s + p_t - \eta\nu_t + \mu_t^{stor,+} \perp q_t^{stor,+} \geq 0, \quad \forall t && \text{(D.14)} \\
& 0 \leq c_s - p_t + \nu_t + \mu_t^{stor,-} \perp q_t^{stor,-} \geq 0, \quad \forall t && \text{(D.15)} \\
& S_{t+1} - S_t - \eta q_t^{stor,+} + q_t^{stor,-} = 0, \nu_t \text{ free} \quad \forall t < T && \text{(D.16)} \\
& 0 \leq -S_t + S_{max} \perp \mu_t^s \geq 0, \quad \forall t && \text{(D.17)} \\
& 0 \leq -q_t^{stor,+} + q_{max}^{stor,+} \perp \mu_t^{stor,+} \geq 0, \quad \forall t && \text{(D.18)} \\
& 0 \leq -q_t^{stor,-} + q_{max}^{stor,-} \perp \mu_t^{stor,-} \geq 0, \quad \forall t && \text{(D.19)}
\end{aligned}
$$

The KKTs are linearized using the Big-M method; see Gabriel and Leuthold (2010). The absolute value in (D.2) is linearized using ancillary non-negative variables:

$$
\begin{aligned}
q_{t+1}^n - q_t^n = q_t^+ - q_t^- \quad \forall t, && \text{(D.20)} \\
q_t^+, q_t^- \geq 0 \quad \forall t, && \text{(D.21)}
\end{aligned}
$$

Ensuring

$$|q_{t+1}^n - q_t^n| = q_t^+ + q_t^- \quad \forall t. \tag{D.22}$$

The objective function $\Pi(q_t^n)$ writes differently depending on the CfD design. In the classical CfD case, the solution is straightforward and displays no coding or computational challenge as the objective function is linear and reads

$$\Pi_{CfD} = \sum_t (s - c) q_t^n.$$

In the other cases, we either have to handle a bilinear term $p_t q_t^n$, with p_t free, or implement a payout of the CfD that depends on the market price being non-negative (in the case of the CfD with negative-price interruption). The latter necessitates some work as it incorporates binary variables directly into the objective function. We handle this non-convexity by using ancillary binary variables and separating the price between its positive and negative components. The problem for the CfD with negative-price interruption is written as

$$\begin{aligned} \max \sum_t (z_t s - p_t^- - c_n) q_t^n \\ \text{s.t.} \quad p_t &= p_t^+ - p_t^- \\ p_t^- &\leq p^{max}(1 - z_t) \\ p_t^+, p_t^- &\in [0, p^{max}] \\ z_t &\in (0, 1) \\ \text{eq. (D.1)-(D.19)} \end{aligned}$$

with p^{max} an upper bound on the absolute value of the price that we set at €3000/MWh, which is the maximum allowed bid on the European power market. This formulation ensures that the nuclear operator receives the strike price s only if the wholesale price is non-negative, and faces the negative market price otherwise, p_t^-.

For the CfD with average reference price, the profit function writes

$$\Pi_{Av} = \sum_t \left[(p_t - c_n) q_n^t \right] + (s - \bar{p}) \sum_t q_n^t$$

Indeed, the nuclear operator faces the market price, p_t, but receives a payout ex post corresponding to the difference between the average price and the strike price, weighted by the total generation from the NPP. Here, the bilinear term $p_t q_n^t$ introduces non-convexity in the objective function that the Gurobi solver handles internally by finding all local optima under a given tolerance threshold and selecting the global optimum out of the list of local optima.

In the case of a Capability CfD the profit function is

$$\Pi_{Cap_{CfD}} = \sum_t (p_t - c_n) q_n^t + (s - p_t) Q_{nuc}$$

If we assume the contract applies to the nameplate capacity of the plant, Q_{nuc}. Here, the bilinear term is also internally handled by the solver, and this case does not need further modeling effort.